Abstract

A method for pressure testing a well system includes: pressurizing testing fluid within a closeable chamber of a well system; determining a leak within the closeable chamber using real time pressure and temperature measurements of the volume of testing fluid within the closeable chamber; and determining the pathway of the leak using real time pressure and temperature measurements of a volume of fluid that is disposed adjacent to the closeable chamber.
SYSTEMS AND METHODS FOR CONDUCTING PRESSURE TESTS ON A WELLBORE FLUID CONTAINMENT SYSTEM

CROSS-REFERENCE TO RELATED APPLICATIONS

[0001] Not applicable.

STATEMENT REGARDING FEDERALLY SPONSORED RESEARCH OR DEVELOPMENT

[0002] Not applicable.

BACKGROUND


[0004] The disclosure relates generally to systems and methods for conducting a pressure test of wellbore service equipment. More particularly, the disclosure relates to systems and methods for reliably and effectively troubleshooting a failed pressure test of wellbore fluid containment system (FCS) equipment, such as blowout preventers (BOPs), choke and kill lines, wellhead hangers, casing, liner and liner hangers, tubing hangers, completions and other equipment.

[0005] 2. Background of the Technology

[0006] In drilling for oil and gas from a hydrocarbon producing well, a well or well system is provided that includes a drilling rig with a riser section and a drill string used to convey drilling fluid down the drill string and through a wellhead to a drill bit disposed within a wellbore of a formation. The fluid recirculates from the drill bit back to the drilling rig via an annulus formed between the drill string and walls of the wellbore, and via the annulus formed between the drill string and the riser section that encircles it. A wellbore or formation fluid influx, also called a “kick”, can cause an unstable and unsafe condition at the drilling rig. When a kick is detected, a FCS of the well system may be actuated and steps may be taken to “kill” the well and regain control. The FCS includes all critical sealing points, including the BOP itself and each of its individual rams, the choke manifold and kill manifolds, an internal blowout preventer (IBOP), as well as other components.

[0007] Due to the criticality of the functional operation of the FCS with regard to containing and managing fluid pressures within the drilling or well system, periodic testing of the FCS is required. As part of the FCS testing procedure, a FCS testing plug may be landed against a sealing surface within the FCS, followed by subsequent pressurization of the FCS. Per current federal regulations, pressure testing of the FCS must be conducted upon installation and before 14 days have elapsed since the last BOP pressure test. Low and high pressure tests must be conducted for each individual component, and each component must demonstrate that it holds a reasonably stable pressure. For instance, in practice a pressure decay rate of 4 pounds per square inch (psi) per minute or less is seen as reasonably stable.

[0008] Even though components of a FCS need only demonstrate pressure holding capability for five minutes to pass a presently-required pressure test, conducting the individual tests often take much longer due to PVT effects that take place during the pressurizing of the test fluid. Specifically, friction generated by the action of pumping a fluid (e.g., via a reciprocating pump) increases the temperature as the fluid is pressurized. Referring to FIG. 1, graph 100 illustrates fluid pressures in relation to time at different positions along a vertically-oriented subsea drill string during a high pressure test. Pressure curve 110 illustrates the fluid pressure at a point within the drill string near the sea floor, with curves 120, 130 and 140 illustrating fluid pressure at progressively shallower points along the drill string, with curve 140 illustrating fluid pressure at the shallowest point, near the surface. Due to being located at different vertical depths along the drill string, curve 110 is at the highest pressure, while curve 140 is at the lowest pressure of the curves.

[0009] As shown in FIG. 1, the high pressure test can be divided into three phases: a pumping phase (112, 122, 132 and 142), a shut-in phase (114, 124, 134 and 144) and a depressurization phase (116, 126, 136 and 146). The pumping phase takes place when testing fluid is pumped into the well system in order to pressurize the FCS. Testing fluid may be pumped into the drill string by a cement unit or mud pump disposed at the drilling rig of the well system. Once the FCS of the well system has been pressurized to the appropriate testing pressure, pumping ceases and the well system is shut-in, such that a portion of the well system containing the system components to be tested is isolated from the outside environment. Shut-in phases 114, 124, 134 and 144 have a beginning (114a, 124a, 134a and 144a) and an ending (114b, 124b, 134b and 144b). As shown by FIG. 1, the pressure at the beginning 114a, 124a, 134a and 144a exceeds the pressure at the end 114b, 124b, 134b and 144b of the shut-in phase. Also, in this pressure test, each shut-in phase includes a pressurization point (114c, 124c, 134c and 144c) at which local additional testing fluid is pumped into the well system to slightly increase fluid pressure within the FCS, known in the field as “bumping up the pressure.” This additional fluid may be pumped in at the pressurization point during the shut-in phase in order to return the fluid pressure within the FCS to the appropriate test pressure, a level similar to that existing near the beginning of the tests, at points 114a, 124a, 134a and 144a.

[0010] The pressure decay occurring during the shut-in phases (e.g., 114, 124, 134 and 144) is due to heat transfer from pressurized fluid within the FCS to fluid in the surrounding environment. As will be discussed in greater detail herein, heat transfer is greater for testing fluid near the surface, as opposed to testing fluid within the FCS that is disposed farther downhole. The greater amount of heat transfer near the surface is due to friction generated during the process of pumping the testing fluid into the well system (e.g., via a cement unit or mud pump) for the purpose of pressurizing testing fluid within the FCS. This heat transfer leads to a greater relative difference in temperature between the testing fluid disposed within the marine riser and ambient water surrounding the drill string at that same vertical depth, resulting in a relatively large amount of heat transfer from the testing fluid disposed near the surface and the ambient water surrounding the drill string at that depth. The total or aggregate pressure decay within the FCS, when there is no fluid leak between the FCS and the surrounding environment, corresponds with the total or net heat transfer out of the fluid disposed within the FCS to the surrounding environment.

[0011] During the performance of the FCS low pressure and high pressure test, an analog low resolution circular chart surface recorder may be used by drilling personnel on the drilling rig to observe a continuous pressure reading of the FCS. Even in cases where the tested FCS component is not...
leaking, the pressure test may often last over half an hour or longer before the pressure within the FCS begins to stabilize enough such that a continuous five minute period of successful pressure stabilization may be recorded. Further, due to pressure decay caused by PVT effects (e.g., pumping effects) and the low resolution of the analog chart recorder, FCS pressure tests are sometimes judged as successful before full stabilization (e.g., decay of 4 psi/min or less), thus allowing for the risk that remaining pressure decay may be due to a leak within the FCS, in addition to PVT effects. In practice, this phenomenon is especially impactful at higher testing pressures, as are required in deeper, hot wells and where oil-based mud (OBM) or synthetic oil. Accordingly, there remains a need in the art for systems and methods that allow for quick and effective pressure testing of well system equipment, such as a FCS. Further, it would be advantageous if such systems and methods would mitigate the PVT effects that take place during a pressure test of well system equipment. Still further, it would be advantageous to provide a system that includes a means providing a continuous pressure signal with a relatively high resolution.

BRIEF SUMMARY OF THE DISCLOSURE

[0012] 1. In an embodiment, a method for pressure testing a well system comprises pressurizing a volume of testing fluid within a closeable chamber of a well system, determining a leak within the closeable chamber using real time pressure and temperature measurements of the volume of testing fluid within the closeable chamber and determining the pathway of the leak using real time pressure and temperature measurements of a volume of fluid disposed adjacent to the closeable chamber. In some embodiments, determining a leak within the closeable chamber comprises determining the change in fluid pressure within the closeable chamber due to a change in volume of the volume of testing fluid within the closeable chamber. In some embodiments, determining the change in fluid pressure within closeable chamber due to a change in volume of the volume of testing fluid within the closeable chamber comprises determining the change in fluid pressure within the closeable chamber due to a change in volume of testing fluid within the closeable chamber using real time pressure and temperature measurements of the volume of testing fluid within the closeable chamber.

[0013] In other embodiments, determining the change in fluid pressure within closeable chamber due to a change in volume of the volume of testing fluid within the closeable chamber comprises measuring in real time a change in fluid pressure within the closeable chamber using a sensor disposed within the closeable chamber.

[0014] In an embodiment, a method for pressure testing a blowout preventer comprises pressurizing a volume of testing fluid within the blowout preventer, determining a leak within the blowout preventer using real time pressure and temperature measurements of fluid disposed within the well system and determining the pathway of the leak using real time pressure and temperature measurements of a volume of fluid disposed adjacent to blowout preventer. In some embodiments, pressurizing the volume of testing fluid within the blowout preventer comprises actuating a ram of the blowout preventer. In some embodiments, pressurizing the volume of testing fluid within the blowout preventer comprises actuating an annular of the blowout preventer. In some embodiments, determining the leak within the blowout preventer using real time pressure and temperature measurements of fluid disposed within the well system comprises determining a leak across a ram of the blowout preventer. In some embodiments, determining the leak within the blowout preventer using real time pressure and temperature measurements of fluid disposed within the well system comprises determining a leak across an annular of the blowout preventer.

[0015] Embodiments described herein comprise a combination of features and characteristics intended to address various shortcomings associated with certain prior devices, systems, and methods. The various features and characteristics described above, as well as others, will be readily apparent to those skilled in the art upon reading the following detailed description, and by referring to the accompanying drawings.

BRIEF DESCRIPTION OF THE DRAWINGS

[0016] For a detailed description of the exemplary embodiments of the invention disclosed herein, reference will now be made to the accompanying drawings in which:

[0017] FIG. 1 is a graph illustrating pressure curves generated during a pressure test of a well system;

[0018] FIG. 2 is a schematic view of an embodiment of a well system configured to conduct a fluid containment system pressure test in accordance with principles described herein;

[0019] FIGS. 3A-3D are perspective views, some in cross-section, showing components of the wired pipe communication network shown in FIG. 3;

[0020] FIG. 4A is a graph illustrating a pressure curve generated during a pressure test of the well system shown in FIG. 3, and

[0021] FIG. 4B is a graph illustrating a temperature curve generated a pressure test of the well system shown in FIG. 3.
DETAILED DESCRIPTION

The following discussion is directed to various exemplary embodiments. However, one skilled in the art will understand that the examples disclosed herein have broad application, and that the discussion of any embodiment is meant only to be exemplary of that embodiment, and not intended to suggest that the scope of the disclosure, including the claims, is limited to that embodiment. The drawing figures are not necessarily to scale. Certain features and components herein may be shown exaggerated in scale or in somewhat schematic form and some details of conventional elements may not be shown in interest of clarity and conciseness.

In the following discussion and in the claims, the terms “including” and “comprising” are used in an openended fashion, and thus should be interpreted to mean “including, but not limited to . . . .” Also, the term “couple” or “couples” is intended to mean either an indirect or direct connection. Thus, if a first device couples to a second device, that connection may be through a direct connection, or through an indirect connection via other devices, components, and connections. In addition, as used herein, the terms “axial” and “axially” generally mean along or parallel to a given axis (e.g., given axis of a body or a port), while the terms “radial” and “radially” generally mean perpendicular to the given axis. For instance, an axial distance refers to a distance measured along or parallel to the given axis, and a radial distance means a distance measured perpendicular to the given axis. Still further, as used herein, the phrase “communication coupler” refers to a device or structure that communicates a signal across the respective ends of two adjacent tubular members, such as the threaded box/pin ends of adjacent pipe joints; and the phrase “wired drill pipe” or “WDP” refers to one or more tubular members, including drill pipe, drill collars, casing, tubing, subs, and other conduits, that are configured for use in a drill string and include a wired link. As used herein, the phrase “wired link” refers to a pathway that is at least partially wired along or through a WDP joint for conducting signals, and “communication link” refers to a plurality of communicatively-connected tubular members, such as interconnected WDP joints for conducting signals over a distance.

A system and method for pressure testing components of a well system is disclosed herein. Embodiments described herein may be employed in various drilling and production applications; however, it has particular application as a system and method for mitigating IPT effects during the pressure testing of pressure containing components of a well system, such as a fluid containment system (FCS). Further, it has particular application with regard to offshore well drilling and production systems.

Referring now to FIG. 2, an offshore well drilling system 10 generally includes an offshore semi-submersible drilling rig 20 disposed at the water line 12 with a derrick 22 and deck 22 having a testing fluid system (TFS) 21 disposed thereon. System 10 further includes a riser 30 that extends between the rig 20 and a wellhead 60 disposed at the sea floor 14, a FCS 40, a drill string 50 disposed within a marine riser 30 and having a central axis 55 and internal passageway 50a. . . . Well system 10 further includes casing 70 that extends downward from a wellhead spool 61 of wellhead 60 and is secured in place via cement 72. TFS 21 is disposed at rig floor 22 and comprises a mud pit 25, a cement unit 27 and a fluid conduit 28. Conduit 28 provides a fluid flowpath 29 for the passage of testing fluid from mud pit 25, through cement unit 27, and to the passageway 50a of drill string 50. Cement unit 27 comprises a high pressure, reciprocating triplex pump. However, in other embodiments cement unit 27 may comprise other components configured to pressurize a fluid. Testing fluid 29 comprises a drilling fluid that may be at a high density or high weight (e.g., drilling fluid, SOBM, completion fluid, etc.) relative to the ambient water 13 disposed below water line 12. For instance, fluid 29 typically has a high enough density to overcome the pressure of fluid within the adjacent formation 16. Alternatively, testing fluid may also comprise a relatively lower density fluid, such as water or base oil.

An annulus 35 is formed between drill string 50 and riser 30 and allows for the recirculation of drilling fluid between rig 20 and a wellbore 62 that extends into subterranean formation 16 from the sea floor 14. FCS 40 generally includes components configured to retain and manage fluid pressure within well system 10 (e.g., drill string 50, FCS 40, annulus 35, wellbore 62, etc.) by acting as a closeable chamber isolating or sealing fluid disposed within well system 10 and the surrounding environment. In the embodiment of well system 10, FCS 40 includes BOP 41, choke line 44, kill line 46 and an internal blowout preventer (IBOP) 48, wellhead 60, wellbore 62, casing 70 as well as other components. BOP 41 includes annular 41a and rams 42, each configured to create an annular seal about drill string 50. For instance, rams 42 of BOP 41 are configured to provide an annular seal 43 about drill string 50 upon actuation, dividing annulus 35 into a first or upper section 35a extending between rig 20 and seal 43 and a second or middle section 35b extending from seal 43 downward to a FCS testing plug 49 coupled to drill string 50.

A third or lower section 35c extends from wellhead 60 into the wellbore 62. Testing plug 49 is configured to prevent fluid flow between middle portion 35b of annulus 35 and a lower portion 35c extending into wellbore 62. Testing plug 49 forms an annular seal 49a against an annular surface 61a of a wellhead spool 61 disposed within wellhead 60. Testing plug 49 is coupled to an end of two adjacent tubular joints 52 extending between adjacent nodes 51 and physically engages upper annular surface 61a of wellhead spool 61 via lower annular surface 49a. A radial port or opening 45 is provided in the drillstring 50 to act as a route of fluid communication between drillstring 50 and the annulus 35 above testing plug 49. During drilling, a pressure spike or kick of fluid from the formation 16 that has a relatively higher pressure than drilling fluid disposed within wellbore 62 may flow into wellbore 62 and travel upward through lower section 35c of annulus 35 (testing plug 49 is not installed in well system 10 during the act of drilling). The formation kick may be trapped or isolated below upper section 35a of annulus 35 via actuating one or more rams 42 of BOP 41 to provide the annular seal 43. Choke line 44 and kill line 46 may be used to provide for alternate routes of fluid communication between rig 20 and annulus 35 such that the testing fluid (e.g., water, drilling mud, etc.) is pumped into FCS 40 to prevent further upward flow of fluid from formation 16.

During a formation kick, an influx of fluid from the formation may be circulated upward through choke line 44 to the rig 20, in an effort to regain control and stabilize the flow of formation fluid into annulus 35 such that fluid pressure within FCS 40 may stabilize. Choke line 44 generally includes a lower valve 44a, a manifold 44b and an upper valve 44c. Fluid flow through choke line 44 may be restricted by closing lower valve 44a or upper valve 44c. Further, choke
manifold 44b includes a plurality of valves, chokes and other equipment, and as such is configured to manage and regulate flow through choke line 44. Because successful control of a formation kick may depend on the effective operation of choke line 44 and its components, valves 44a, 44c, and manifold 44b are individually pressure tested during the pressure testing of FCS 40. Kill line 46 is also used to manage a formation kick by allowing for circulation between annulus 35 and rig 20. For instance, kill line 46 is used as a route of fluid communication to pump high density drilling mud or other fluid downward from rig 20 to the annulus 35 to forcibly maintain the fluid from the formation kick or influx within the wellbore 62. Thus, a kill line such as kill line 46 may be used to “kill” the well by reversing, stopping or at least substantially restricting the flow of fluid from the formation into the wellbore 62 by pumping heavy fluid into the entire fluid circulation system (e.g., annulus 35, choke line 44, kill line 46, etc.) from the rig 20. Kill line 46 comprises a lower valve 46a, a kill manifold 46b and an upper valve 46c. As with choke line 44, flow through kill line 46 may be substantially restricted or controlled via valves 46a, 46c, and manifold 46b. Thus, during pressure testing of FCS 40, valves 46a, 46c and manifold 46b are pressure tested as well.

Another component of FCS 40, IBOP 48, is disposed at an upper end 50b of drill string 50 at the rig 20 and is configured to manage fluid pressure within drill string 50. For instance, during a formation kick, high pressure formation fluid may begin flowing upward through string 50 via an opening or port of the string 50 disposed within wellbore 62 (e.g., at the drill bit). For instance, IBOP 48 includes a valve that allows for the passage of fluid into string 50 but may be closed to restrict fluid from flowing out of string 50 through IBOP 48 in the event of a formation kick. Thus, because IBOP 48 may be used in effectively controlling a formation kick, IBOP 48 is pressure tested during the pressure testing of FCS 40.

Referring now to FIGS. 2 and 3A-3D, drill string 50 comprises a plurality of nodes 51 (e.g., 51a-51d, etc.) coupled between the plurality of tubular joints 52. Wired or networked drill pipe incorporating distributed sensors can transmit data from anywhere along the drill string 50 to the rig 20 for analysis. Nodes 51 are provided at desired intervals along the drill string 50. Network nodes 51 essentially function as signal repeaters to regenerate and/or boost data signals and mitigate signal attenuation as data is transmitted up and down the drill string. The nodes 51 may also include measurement assemblies. The nodes 51 may be integrated into an existing section of drill string or a downhole tool along the drill string 50. For purposes of this disclosure, the term “sensors” is understood to comprise sources (to emit/transmit energy/signals), receivers (to receive/detect energy/signals), and transducers (to operate as either source/receiver). Tubular joints 52 include a first pipe end 53 having, for example, a first induction coil 53a and a second pipe end 54 having, for example, a second induction coil 54a.

Nodes 51 comprise a portion of a wired pipe communication network 56 that provides an electromagnetic signal path that is used to transmit information along the drill string 50. The communication network 56, or broadband network telemetry, may thus include multiple nodes 51 based along the drill string 50. Communication links or wired conductors 52a may be used to connect the nodes 51 to one another, and may comprise cables or other transmission media integrated directly into sections of the drill string 50. The cable may be routed through the central borehole of the drill string 50, or routed externally to the drill string 50, or mounted within a groove, slot or passageway in the drill string 50. Signals from the plurality of sensors of nodes 51 along the drill string 50 are transmitted to rig 20 through wire conductors 52a along the drill string 50. Communication links 52a between the nodes 51 may also use wireless connections. A plurality of packets may be used to transmit information along the nodes 51. Further detail with respect to suitable nodes, a network, and data packets are disclosed in U.S. Pat. No. 7,207,396 (Hall et al., 2007), hereby incorporated in its entirety by reference. Various types of sensors 57 may be employed along the drill string 50 in various embodiments, including without limitation, axially spaced pressure sensors, temperature sensors, and others. The sensors 57 may be disposed on the nodes 51 positioned along the drill string, disposed on tools incorporated into the drill string, or a combination thereof. Sensors 57 of nodes 51 may measure properties of fluid disposed within string 50 or within annulus 35 or wellbore 62. Thus, sensors 57 of nodes 51 (e.g., nodes 51a-51d) may measure temperature, pressure, etc., of fluid within string 50 or annulus 35 of wellbore system 10.

Network nodes 51 are disposed along the drill string 50 between joints 52. In some embodiments, the booster assemblies are spaced at 1,500 ft. (500 m) intervals to boost the data signal as it travels the length of the drill string 50 to prevent signal degradation. Network nodes 51 are also located at these intervals to allow measurements to be taken along the length of the drill string 50. The distributed network nodes 51 provide measurements that give the driller additional insight into what is happening along the potentially miles-long stretch of the drill string 50.

Rig 20 includes a well site computer 58 that may display information for the drilling operator. The wired pipe communication network 56 transmits information from each of a plurality of sensors 57 to a surface computer 58. Information may also be transmitted from computer 58 to another computer 59, located at a site remote from the well, with this computer 59 allowing an individual in the office remote from the well to review the data output by the sensors 57. Although only a few sensors 57 are shown in the figures, those skilled in the art will understand that a larger number of sensors may be disposed along a drill string (e.g., drill string 50) when drilling, and that all sensors associated with any particular node may be housed within or annexed to the node 51, so that a variety of sensors rather than a single sensor will be associated with that particular node.

Due to the risk of losing control of well system 10 (i.e., the uncontrolled flow of formation fluids into well system 10) caused by an uncontrolled wellbore influx of fluid from the formation, it is important to detect the influx as soon as possible. In some circumstances, a BOP (e.g., BOP 41) of the FCS (e.g., FCS 40) is actuated to close off the well above the wellbore influx. In some cases, for example in deepwater wells, the wellbore influx may migrate above the BOP before a ram of the BOP fully closes to seal off the wellbore. In the embodiments disclosed herein, the wired pipe communication network 56 allows wellsite personnel to identify potential remedial actions for the migrated wellbore influx. In some embodiments, the measurements used are independent from surface measurements.

One or more embodiments of a well drilling system 10 comprising a fluid containment system 40 and a testing fluid system 21 having been disclosed, one or more embodi-
ments of a method of pressure testing components of the FCS 40 are also disclosed herein. Further, one or more embodiments of a method for evaluating or troubleshooting the results of a failed pressure test of components of FCS 40 are disclosed herein. In an embodiment, a FCS pressure testing method generally includes the steps of engaging a testing plug of the FCS against a sealing surface within the FCS (e.g., a wellhead spool), disposing a quantity of testing fluid (e.g., drilling fluid, etc.) within the FCS, isolating a portion of the FCS (e.g., actuating a ram or annular of the BOP closing a valve of the choke line, etc.), displacing an additional quantity of testing fluid into the FCS to increase the fluid pressure within the FCS to a predetermined testing pressure, shutting the FCS by ceasing the displacement of testing fluid into the FCS, continuously in real-time monitor fluid pressure within the FCS via a wired pipe communication network for a period of time.

[0037] In the event that the FCS is unable to hold a relatively stable fluid pressure for a predetermined period of time (e.g., five minutes), the failed pressure test may be evaluated by continuously monitoring fluid pressure during the shut-in phase within cavities adjacent to the FCS component being tested. Following this, the particular leak path resulting in the failed FCS pressure test may be determined by determining which adjacent cavity of the FCS increased in fluid pressure during the course of the shut-in phase of the pressure test. By determining the particular leak path, it may be further determined whether the particular FCS component being tested (e.g., a ram of the BOP) was at least partially responsible for the leak or whether another component was responsible for the leak path (e.g., the FCS testing plug). Optionally, following the methods of FCS pressure testing and evaluation, the particular components of the well system responsible for the leak path may be replaced and the pressure test may be conducted again in an effort to achieve a successful pressure test of the particular FCS component.

[0038] In an embodiment, ram 42 of BOP 41 may be pressure tested as part of the regime for pressure testing each individual component of FCS 40. In this embodiment, testing plug 49 is coupled to drill string 50 and disposed downward through marine riser 30 until annular surface 49a of tool 49 engages annular surface 61a of wellhead spool 61 to create annular seal 49c, which divides annulus 35 into upper section 35a and lower section 35c. Before, during or after sealing engagement has been achieved between tool 49 and spool 61, high density testing fluid 29 (e.g., drilling fluid, SOBM, competition fluid, etc.) is disposed within drill string 50 and riser 30 at a relatively low pressure using cement unit 27 and flowpath 29a. Also, prior to commencement of the pressure testing of FCS 40, ram 42 of BOP 41 is actuated to form an annular seal 43 against an outer surface of drill string 50, substantially preventing testing fluid from a port 45 of string 50 from flowing upward into the upper section 35a of annulus 35. Thus, annular seals 49c and 43 form middle section or closable annular chamber 35b within marine riser 30. During the course of the pressure testing of ram 42, pressure and temperature of fluid within annulus 35 and drill string 50 is continuously measured at different vertical depths along string 50 via nodes 51a-51d etc. For instance, pressure and temperature of fluid within chamber 35b is continuously measured via node 51b while pressure and temperature in upper portion 35a and lower portion 35c are measured via nodes 51d and 51c, respectively. Measurements taken by sensors 57 at nodes 51 (e.g., nodes 51a-51d) are continuously transmitted to computers 58 or 59 at rig 20 via wired pipe communication network 56.

[0039] Following the engagement of annular seals 49c and 43, fluid pressure within drillstring 50 and chamber 35b of annulus 35 is increased to a predetermined testing pressure by displacing a volume of testing fluid 29 into chamber 35b via port 45. Testing fluid 29 is pumped using cement unit 27 into drill string 50 via fluid flowpath 29a, which comprises mud pit 25, cement unit 27 and passageway 50a of string 50. Testing fluid 29 within chamber 35b is subsequently pressurized to approximately between 5,000-15,000 psi by cement unit 27. During the process of pressurizing testing fluid within chamber 35b, testing fluid 29 is disposed within choke line 44 and kill line 46, preventing fluid within chamber 35b from flowing up lines 44, 46, via the weight of the fluid 29 disposed within lines 44, 46.

[0040] Referring now to FIGS. 2, 4A and 4B, pressure graph 500 illustrates pressure curve 510 as measured by and transmitted from node 51b, and temperature graph 600 illustrates temperature curve 610 of additional testing fluid 29 pumped into FCS 40 as measured by and transmitted from node 51b during the FCS 40 pressure test illustrated in FIG. 2. As shown in FIG. 2A, pressure curve 510 comprises a pumping phase 512, a shut-in phase 514 having a beginning 514a and an end 514b, and a depressurization phase 516. During pumping phase 512, testing fluid 29 is pumped into drillstring 50 via cement unit 27, which in turn displaces a volume of fluid into chamber 35b, pressurizing the chamber 35b to the predetermined testing pressure. Once pressure within chamber 35b has reached the FCS testing pressure, the beginning 514a of shut-in phase 514 initiates with the cessation of pumping from cement unit 27, stopping the flow of testing fluid 29 into drillstring 50 at rig 20. As part of the BOP pressure test shown in FIG. 2, ram 42 must successfully hold the FCS test pressure for a specified period of time. In one example, ram 42 must hold 15,000 psi for a period of five minutes. Friction from pumping results in an increase in temperature of the additional testing fluid 29 pumped into FCS 40 and string 50 from mud pit 25. During shut-in phase 514, heat generated within the pumped-in testing fluid 29 begins to transfer out into fluid occupying riser 30 and/or the ambient seawater 13 surrounding riser 30. Thus, at least partially due to the transfer of heat from testing fluid 29, fluid pressure within chamber 35b steadily decreases in response to the decreasing temperature of fluid within FCS 40, especially with regard to the additional testing fluid 29 pumped into FCS 40 from mud pit 25.

[0041] As discussed previously, friction from pumping results in an increase in temperature of testing fluid 29 pumped into FCS 40. As shown in FIG. 4B, temperature curve 610 illustrates the transfer of heat from the pumped-in testing fluid 29 into fluid within riser 30 and/or ambient seawater 13 surrounding riser 30. As fluid 29 decreases in temperature (as measured near the water line 12 by node 51d), it in turn decreases in volume due to PVT effects, resulting in a corresponding decrease in pressure over time of fluid within chamber 35b (as measured by node 51b). The pressure loss within chamber 35b due to the drop in temperature (\(dP_T\)) of the pumped-in testing fluid 29 may be calculated in real time and subtracted from the total pressure drop (\(dP\)) to arrive at a pressure drop due to a change in volume of FCS 40 (i.e., pressure drop caused by a leak within chamber 35c) (\(dP_L\)) over a given period of time. The \(dP_T\) of testing fluid 29 within
chamber 35b may be calculated given the volumetric coefficient of thermal expansion ($\alpha$) and the compressibility factor ($\beta$) of the testing fluid 29 (e.g., SOBM, completion fluid, etc.).

[0042] Using the pressure curve 510 and temperature curve 610 data measured by nodes 51a and 51d, the dP$_v$ of fluid within chamber 35c is calculated in real time. Thus, in the absence of a leak, the dP$_v$ should remain substantially stable during the shut-in phase of the BOP test, with five minutes of stable dP$_v$ satisfying the conditions of the BOP test. Thus, relying on the real time dP$_v$ of fluid within chamber 35b allows for a relatively timelier BOP pressure test because the test conductor (e.g., drilling operator at rig 20) will not have to wait on the dP of fluid within testing fluid system 21, which must follow stabilization of the temperature of fluid within FCS 40 (especially the additional pumped-in testing fluid). Thus, shut-in phase 514 may have a relatively shorter duration than the shut-in phases shown in FIG. 1, as the requirement of holding the BOP test pressure (e.g., 15,000 psi) within chamber 35b for a specified amount of time (e.g., five minutes) will be satisfied more quickly due to the stability of calculated dP$_v$ versus measured dP, allowing for a faster BOP pressure test.

[0043] Further, while in this example temperature data from node 51d is relied upon in determining dP$_v$ in other embodiments temperature data may be measured and transmitted from a plurality of nodes spanning the length of drill string 50 between test plug 49 and rig 20, allowing for the computation of the overall dP$_v$ for all of the testing fluid 29 within string 50, flowpath 29a and chamber 35b of FCS 40.

[0044] In some cases, a leak will occur within chamber 35b, possibly at seal 43 provided by ram 42 or at seal 49, provided by BOP testing tool 49. A leak may be determined by a drilling operator at rig 20 in real time via the dP$_v$ of fluid within chamber 35b during shut-in phase 514, which may be calculated from the measured pressure curve 510 and temperature curve 610 of the fluid. For instance, if the dP$_v$ steadily decreases during shut-in phase 514, then a leak has occurred within chamber 35b, regardless of any temperature changes in the fluid within chamber 35b. If seal 43 is allowing fluid within chamber 35b to pass into upper portion 35a of annulus 35, then BOP 41 has failed the BOP pressure test and a new ram 42, annular BOP or BOP 41 may need to be installed before the drilling operation may be continued. However, if a faulty seal 49 is responsible for the fluctuation of the dP$_v$ of fluid within chamber 35b, then a new BOP testing tool 49 may be installed and a new BOP pressure test conducted, without yet having to replace ram 42 or BOP 41. For instance, continuous pressure and temperature measurements of fluid within lower portion 35c of annulus 35 may be taken at node 51c to calculate a real time dP$_v$ of fluid within lower portion 35c. If the dP$_v$ of fluid within lower portion 35c increases during shut-in phase 514, then fluid within pressurized chamber 35b is leaking past seal 49e of tool 49 and into lower portion 35c of annulus 35. However, if the dP$_v$ of fluid within lower portion 35c remains stable during shut-in phase 514, then fluid is not leaking into lower portion 35c, and the cause of the leak within chamber 35b must extend to a different portion of the FCS 40 and/or well system 10. Also, a real time dP$_v$ of fluid within upper portion 35a of annulus 35 may be calculated using real time temperature and pressure measurements of the fluid via node 51a. In this example, if the dP$_v$ of fluid within upper portion 35a increases during shut-in phase 514, then fluid is leaking into upper portion 35a via a leak within seal 43 of ram 42, resulting in a failure by BOP 41 of the BOP pressure test.

[0045] Referring back to FIG. 2, in addition to ram 42 of BOP 41, other components of FCS 40 may be pressure tested in a similar manner. For instance, other individual rams of BOP 41 may be actuated to create an annular seal within annulus 35, forming a cavity defined by the ram’s annular seal and the seal 49a produced by BOP testing plug 49. Likewise, lower valves 44a, 46a, manifolds 44b, 46b, and upper valves 44c, 46c of choke line 44 and kill line 46, respectively, may be pressure tested by placing nodes (e.g., nodes similar to nodes 51) within choke line 44 or kill line 46 in order to continuously measure and transmit pressure and temperature readings from lines 44, 46. In order to test the components of choke line 44 and kill line 46, high density testing fluid 29 is pumped into drillstring 50 via cement unit 27. Ram 42 of BOP 41 may be actuated to create annular seal 43. However, instead of allowing fluid communication between choke line 44 and kill line 46 with chamber 35b, a component of lines 44, 46, may be sealed (e.g., lower valve 44a). In this embodiment, the sealed component (e.g., valve 44a) may be pressure tested to see if it holds the BOP test pressure for a requisite period of time (e.g., five minutes).

[0046] While embodiments have been shown and described, modifications thereof can be made by one skilled in the art without departing from the scope or teachings herein. The embodiments described herein are exemplary only and are not limiting. Many variations and modifications of the systems, apparatus, and processes described herein are possible and are within the scope of the invention. Accordingly, the scope of protection is not limited to the embodiments described herein, but is only limited by the claims that follow, the scope of which shall include all equivalents of the subject matter of the claims. Unless expressly stated otherwise, the steps in a method claim may be performed in any order. The recitation of identifiers such as (a), (b), (c) or (1), (2), (3) before steps in a method claim are not intended to and do not specify a particular order to the steps, but rather are used to simplify subsequent reference to such steps.

What is claimed is:

1. A method for pressure testing a well system comprising: pressurizing a volume of testing fluid within a closeable chamber of a well system; determining a leak within the closeable chamber using real time pressure and temperature measurements of the volume of testing fluid within the closeable chamber; and determining the pathway of the leak using real time pressure and temperature measurements of a volume of fluid disposed adjacent to the closeable chamber.

2. The method of claim 1, wherein determining a leak within the closeable chamber comprises determining the change in fluid pressure within the closeable chamber due to a change in volume of the volume of testing fluid within the closeable chamber.

3. The method of claim 2, wherein determining the change in fluid pressure within closeable chamber due to a change in volume of the volume of testing fluid within the closeable chamber comprises subtracting the change in fluid pressure within the closeable chamber due to a change in temperature of the volume of testing fluid within the closeable chamber from the total change in fluid pressure within the closeable chamber.
4. The method of claim 1, wherein pressurizing fluid within a closeable chamber of a well system comprises flowing fluid into the closeable chamber.

6. The method of claim 2, wherein determining the change in fluid pressure within closeable chamber due to a change in volume of the volume of testing fluid within the closeable chamber comprises measuring in real time a change in fluid pressure within the closeable chamber using a sensor disposed within the closeable chamber.

7. The method of claim 2, wherein determining the change in fluid pressure within closeable chamber due to a change in volume of the volume of testing fluid within the closeable chamber comprises measuring in real time a change in fluid temperature within the closeable chamber using a sensor disposed within the closeable chamber.

8. The method of claim 1, wherein determining the pathway of the leak using real time pressure and temperature measurements of a volume of fluid disposed adjacent to the closeable chamber comprises disposing a sensor within the volume of fluid disposed adjacent to the closeable chamber.

9. The method of claim 8, wherein detecting a pressure increase within the volume of fluid disposed adjacent to the closeable chamber comprises determining the change in fluid pressure within the volume due to a change in volume of the volume of fluid disposed adjacent to the closeable chamber.

10. The method of claim 1, wherein determining a leak within the closeable chamber using real time pressure and temperature measurements comprises transmitting the pressure and temperature measurements of the volume of testing fluid to a computer of the well system.

11. The method of claim 1, wherein the closeable chamber is formed using a blowout preventer and a testing plug.

12. The method of claim 11, wherein the pathway of the leak comprises a sealing surface of the blowout preventer.

13. The method of claim 11, wherein the pathway of the leak comprises a sealing surface of the testing plug.

14. The method of claim 1, wherein the closeable chamber comprises a component of a fluid containment system.

15. A method for pressure testing a blowout preventer comprising:
   pressurizing a volume of testing fluid within the blowout preventer;
   determining a leak within the blowout preventer using real time pressure and temperature measurements of fluid disposed within the well system; and
   determining the pathway of the leak using real time pressure and temperature measurements of a volume of fluid disposed adjacent to blowout preventer.

16. The method of claim 15, wherein pressurizing the volume of testing fluid within the blowout preventer comprises actuating a ram of the blowout preventer.

17. The method of claim 15, wherein pressurizing the volume of testing fluid within the blowout preventer comprises actuating an annular of the blowout preventer.

18. The method of claim 15, wherein determining the leak within the blowout preventer using real time pressure and temperature measurements of fluid disposed within the well system comprises determining a leak across a ram of the blowout preventer.

19. The method of claim 15, wherein determining the leak within the blowout preventer using real time pressure and temperature measurements of fluid disposed within the well system comprises determining a leak across an annular of the blowout preventer.

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